

Exploring Demand Charge Savings from Residential Solar

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Overview

Retail electricity tariffs with demand charges, whereby electricity customers are charged based on their peak demand, are commonly used for commercial customers and are increasingly being considered for residential customers as well. Recent discussions have focused in particular on the application of demand charges for residential customers with rooftop solar, as a potential means of better aligning customer bill savings from solar with utility cost savings. These discussions, however, have been hampered by limited information about what level of demand charge savings customers might realistically expect to achieve from rooftop solar: a complex question, given variations in demand charge designs, customer loads, and PV generation profiles.

To inform these ongoing deliberations, Lawrence Berkeley National Laboratory (Berkeley Lab) and the National Renewable Energy Laboratory (NREL) are jointly engaged in a series of studies to evaluate the potential role of demand charges in aligning customer bill savings and utility cost savings from rooftop solar. The analysis summarized here is the first in this series of studies. It focuses specifically on residential customers with solar and seeks to answer the basic question: To what extent, and under what conditions, can rooftop solar reduce residential demand charges? As described further below, the analysis addresses this question by estimating demand charge savings from residential solar across a broad range of demand charge designs, locations, and PV system characteristics.

Subsequent analyses in this series will address other key, related topics, including: demand charge reductions from commercial solar, incremental demand charge reductions from storage combined with solar, and the overall alignment between demand charge savings and utility cost savings.

Data and Methods

The analysis is based on 30-minute weather data spanning a 17-year historical period (1998-2014), sourced from the [National Solar Radiation Database](#). Using those data, we simulate building loads for single-family homes using the [Energy+ Residential Prototype Building Models](#). The simulations are performed across 15 U.S. cities and for multiple home heating types, foundation types, and building vintages. Using the same weather data, we simulate rooftop PV generation using [NREL's System Advisor Model](#). These simulations are performed for the same set of U.S. cities and across multiple PV system sizes (ranging from 20% to 100% of each customer's annual energy consumption) and orientations (south, southwest, west, and flat). This set of simulations yields 12,960 pairs of building load and PV generation data, with each pair based on the same location and time period.

For each pair of load/PV data, we estimate monthly demand charge savings from solar, by comparing demand charges with and without solar, under numerous demand charge designs. Under the "basic" non-coincident demand charge, the customer is charged for its maximum demand during any 30-minute interval over the course of each month. We also estimate demand charge savings under designs with seasonally varying demand charges, with ratchets, with averaging intervals of varying lengths, and with charges based on the customer's maximum demand during specified peak period windows.

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Key Findings

We compare demand charge savings across the various permutations of load/PV data and demand charge designs in terms of the average reduction in monthly demand charges over the entire 17-year analysis period. We present these results in terms of two metrics. The first metric, shown in the top of Figure 1, is the percentage reduction in average billing demand, relative to the customer's billing demand without PV. The second metric, shown in the bottom of Figure 1, is referred to as the *demand charge capacity credit* (DCCC); it is equal to the average reduction in billing demand divided by the PV system nameplate capacity, and serves as a point of comparison to the capacity credit used to assess avoided utility system costs. In addition to comparing average demand charge reductions, we also compare *variability* in monthly demand charge savings across demand charge designs, though those results are included only in the full briefing.

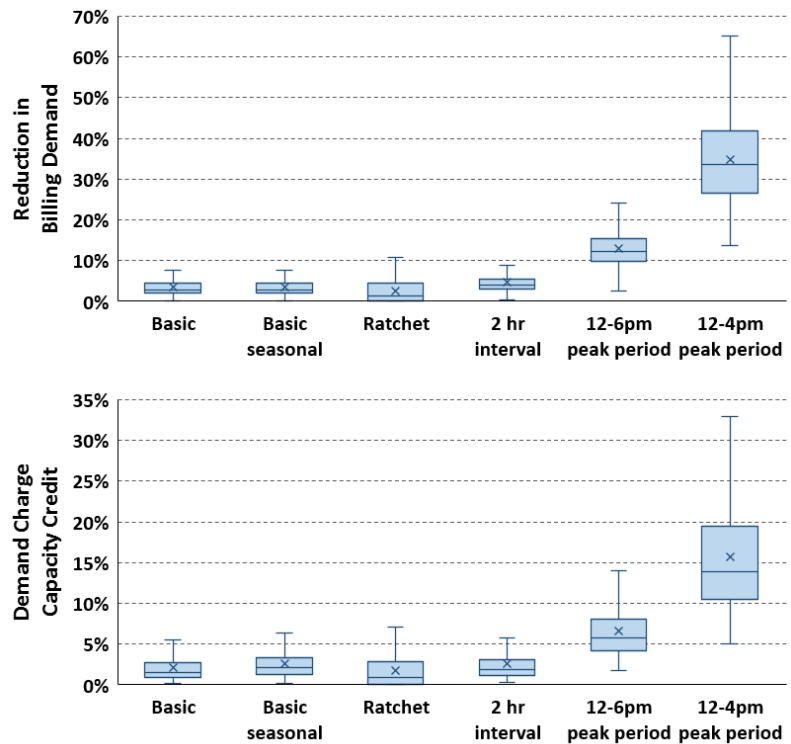


Figure 1. Distribution in average billing demand reduction (top) and DCCC (bottom) for various representative demand charge designs

Notes: Each box-and-whiskers plot shows the distribution in the average monthly reduction in billing demand, across all 12,960 combinations of simulated load and PV generation profiles. PV system sizes range from 20% to 100% of each customer's annual energy consumption. 'x' = mean; shaded box = 25th-75th percentile range; middle line = median; whiskers exclude outliers.

Under the “basic” demand charge design, residential solar is not effective at reducing demand charges. As shown in Figure 1 (the left-most bar segment), rooftop solar reduces demand charges by just 3% in the median case (DCCC = 2%) and by less than 8% in virtually all cases, when based on a basic non-coincident demand charge. Demand charge savings are negligible under this design, because most residential customers have loads that peak in the late afternoon or evening hours, when PV systems generate little or no electricity.

Demand charge savings may be significantly greater when based on pre-defined peak periods. For example, if based on the customer's maximum demand during the 12-4 pm period, residential solar reduces demand charges by 34% in the median case (DCCC = 14%), and by 50% or more in some cases, as illustrated in Figure 1. Under demand charge designs with peak periods that end later in the day, for example a 12-6 pm peak period, demand charge savings from solar are significantly lower. This is because customer peak demand tends to occur at the tail end of the peak period window, when solar output is lower. Also evident in Figure 1, peak period demand charge savings vary considerably across customers. As discussed further below, that variability is primarily the result of differences in geographical location and PV system size.

Other demand charge design elements generally have less significance for bill savings from solar.

We model other demand charge design variations, including: *seasonally varying charges* (with demand charge rates in summer months 3 times higher than in other months), *ratchets* (with billing demand equal to at least 90% of the maximum billing demand in the previous 12 months), and *longer averaging intervals* (of 1, 2, or 4 hours in length, compared to 30 minutes under the “basic” design). As shown in Figure 1, these demand charge variations have virtually no impact on demand charge savings from solar, relative to the basic non-coincident peak demand charge. Though not shown here, these demand charge design elements may take on greater significance when combined with a 12-4 peak period demand charge. The length of the averaging interval, in particular, can have a significant impact on demand charge savings in regions with intermittent cloudiness, by smoothing out short-duration cloud effects on solar output (see pp. 30-31 of the full briefing). Also, independent of its impact on *average* demand charge savings, ratchets can result in much greater *month-to-month variability* in demand charge savings (see p. 37 of the full briefing).

Demand charge savings from solar can vary significantly by location.

While demand charge savings under the basic demand charge design are negligible in all locations, demand charge savings under a 12-4 pm peak period demand charge are significantly higher in some locations than others. For example, as shown in Figure 2, the median DCCC is 27% for systems installed in Phoenix, compared to 9% for systems in Seattle. This locational variation derives in part from differences in load shapes: in particular, higher loads during the 12-4 pm window, generally associated with air-conditioning, allow for deeper demand charge savings. Locational variation also derives from differences in cloudiness: in cities with frequent cloudy days, billing demand is more likely to be set on a cloudy day, leading to lower demand charge savings from solar.

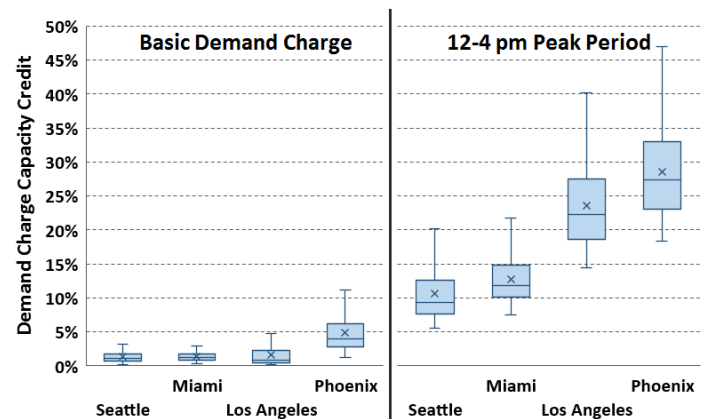


Figure 2. Distribution of DCCC across cities

Demand charge savings increase with PV system size, but with diminishing returns. In contrast to volumetric energy charges, demand charge savings do not scale in proportion to PV system size. For example, under a demand charge based on a 12-4 pm peak period, a system sized to meet just 20% of the customer’s annual energy needs reduces demand charges by 20% in the median case, but if sized to meet 100% of the customer’s annual energy needs reduces demand charges by only 44% (see p. 19 in the full briefing). This occurs for several reasons: larger systems push peak demand to later in the day; larger systems push peak demand to cloudy days; and, under peak period demand charge designs, demand charges in some months can be eliminated, in which case further increases in system size yield no additional savings. As a result of these

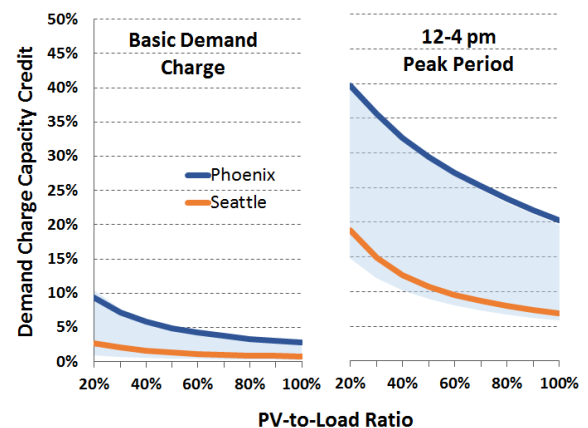


Figure 3. Change in DCCC with increasing PV system size

Notes: PV-to-load ratio equals annual PV generation divided by the customer’s total annual consumption. Solid lines represent average values across all PV/load combinations for the cities shown; shaded areas represent 5th/95th percentile values across all cities.

diminishing returns, the DCCC of residential solar declines with system size, as shown in Figure 3. For example, for a system in Phoenix, the average DCCC under a 12-4 pm peak period demand charge drops from 40% to 20%, across the range of PV system sizes modeled.

Orienting PV panels westward yields, at most, only slight increases in demand charge savings. Southwest- and west-facing panels peak later in the day, coinciding better with load than south-facing panels. The greatest benefits from orienting panels westward, in terms of increasing the demand charge savings, occur for relatively small systems—but even then, are generally quite modest, as shown in Figure 4. For example, for a system in Phoenix, sized to meet just 20% of the customer’s annual energy consumption (a 20% PV-to-load ratio), the average DCCC under a 12-6 pm peak demand charge rises from 17% for a south-facing system to 22% for a southwest-facing system. The average DCCC for the same system would rise from 8% to 11% under a basic non-coincident demand charge, and from 40% to 43% under a 12-4 pm peak period demand charge, if panels are oriented to the southwest rather than due-south. For larger systems (i.e., larger PV-to-load ratio), or for systems installed in cloudier locations (e.g., Seattle), orienting panels to the southwest or west yields smaller, if any, gain in DCCC. One reason why orienting panels westward produces only modest gains in the DCCC is that system sizes must correspondingly increase in order to maintain a given PV-to-load ratio; as noted previously, the DCCC declines with system size, thus counteracting some of the benefit of greater coincidence between the PV generation and load profiles.

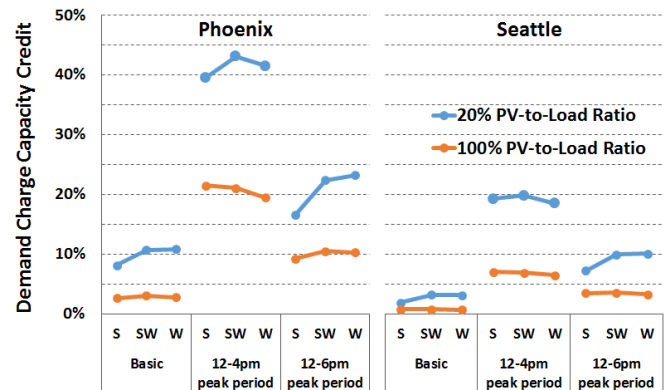


Figure 4. Change in DCCC across PV panel orientations

Demand charge savings are modestly greater for homes with electric space heating. The simulated building loads used in this analysis encompass only a limited set of variations in building characteristics: namely, building vintage, foundation type, and space heating type. In general, only negligible differences in demand charge savings occur across these building characteristics (see p. 36 in the full briefing). Some modest differences in demand charge savings may occur between homes with electric and gas space heating. For example, under a 12-4 pm peak period demand charge, a small PV system in Phoenix yields an average DCCC of 42% in homes with an electric heat pump, compared to 38% in homes with a gas furnace. In most other circumstances—i.e., larger systems, systems installed in cloudier locations, or other demand charge designs—the variations in demand charge savings across building characteristics are even smaller.

Conclusions

This analysis represents only the initial findings in a larger sequence of studies that will assess the potential for demand charges to align customer bill savings from solar with underlying utility cost savings. As such, the findings presented here do not allow for a definitive evaluation of demand charges for solar customers. Later analysis will quantify demand charge savings for commercial customers and for solar combined with storage, and will also consider more directly how those bill savings compare to underlying utility cost savings.

Several other limitations in the methodology and scope of this work are also of note. First, it is based on 30-minute interval data, whereas existing demand charges are often based on 15-minute averaging intervals; as our results show, shorter averaging intervals generally result in smaller demand charge savings. Second, the simulated building loads used in this analysis do not capture all sources of variability in customer loads—e.g., variations in occupancy patterns or all possible variations in end-use equipment—nor do they account for possible load shifting behavior that might occur as a result of demand charges. Finally, although the analysis encompasses a wide variety of demand charge designs, not all possible demand charge rate structures are considered; for example, we did not evaluate tiered demand charge rates, or demand charges based on peak demand averaged over multiple days.

Notwithstanding the limitations above, the findings presented here support several conclusions, with implications for ongoing rate reform efforts:

- **Moving away from fully volumetric electricity rates to demand charges (with lower volumetric rates) will generally reduce bill savings from residential solar.** The erosion in bill savings is most acute in locations with frequent cloud cover and for systems sized to meet a relatively large fraction of building load. Greater use of demand charges would, thus, likely not only reduce growth in the number of PV systems installed, but also in the size of systems installed. Load management and behind-the-meter storage, though not considered in this analysis, could mitigate the erosion in bill savings associated with a move towards demand charges—though at some cost, and both types of measures can be used to manage demand charges even in the absence of solar. As we show, orienting PV panels to the southwest or west has rather limited value as a strategy for enhancing demand charge savings.
- **Some demand charge designs are clearly better than others for solar customers.** When based on non-coincident peak demand, residential solar has virtually no ability to reduce demand charges, given the tendency of residential loads to peak in the late afternoon or evening hours. Other demand charge designs, such as those based on peak periods spanning early and mid-afternoon hours and with relatively long averaging intervals, may offer some savings opportunity from solar. However, even under relatively favorable conditions—e.g., a sunny location, optimal panel orientation, and relatively small PV system size—the bill savings from solar under “PV friendly” demand charge tariffs would still likely be considerably less than under most volumetric energy charges.
- **In some cases, demand charges may align with utility cost savings from residential solar.** Demand charges are often advanced on the basis that they align customer bills with cost causation, particularly for capacity costs driven by peak demand. Although this study does not directly compare demand charge savings to utility cost savings, and therefore cannot comprehensively assess their alignment, the findings suggest that—at least in some cases—demand charges may align reasonably well with avoided capacity costs from residential solar. For example, at high solar penetration levels (when the capacity value of solar is low), or for demand charges that serve only to recover distribution system costs (which, on predominately residential circuits, often peak in late afternoon or evening hours), the relatively low demand charge capacity credit that residential solar receives under many demand charge designs may be appropriate. Future analyses in this series of studies will evaluate these issues in more detail.

- **In other cases, demand charges may *not* align well with utility cost savings from residential solar.** First, at the bulk power system level, solar is generally recognized to provide some capacity value; for example, for summer-peaking electric systems with relatively low overall solar penetration, solar may have a capacity credit in the range of 30-50%.¹ As the preceding results show, the demand charge capacity credit received by residential solar customers is generally less than that amount (often close to zero). Demand charges that are intended to recover bulk power system capacity costs would therefore tend to under-compensate solar customers for the utility cost savings they provide, at least at low system-level solar penetrations. Second, as the results presented here show, demand charge savings from solar exhibit diminishing returns to scale; that is, larger systems do not generate proportionally larger demand charge savings. There is little economic rationale for this relationship: though utility cost savings would be expected to decline with overall solar penetration levels, that relationship would not be expected to hold for individual household PV systems. Instead, to the extent that individual residential rooftop solar provides capacity value to the utility, that value would be expected to scale with the size of the system, and a well-aligned compensation mechanism would mirror that structure.

¹ For a summary of solar capacity credit assumptions used by utilities in their integrated resource plans, see: Mills et al. 2016. [Planning for a Distributed Disruption: Innovative Practices for Incorporating Distributed Solar into Utility Planning](#). Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1006047.

For More Information

Download the detailed slide-deck briefing

Darghouth N., G. Barbose, A. Mills, R. Wiser, P. Gagnon, and L. Bird. 2017. *Exploring Demand Charge Savings from Residential Solar*. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1007030.
<https://emp.lbl.gov/publications/exploring-demand-charge-savings>

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